

# Effects of Salt River Project's Demand-Based Rate Change on the Rooftop Solar Market in Maricopa County, Arizona

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## I. INTRODUCTION

Distributed solar photovoltaic (PV) generation is forcing electric utilities and their customers to re-evaluate how distributed resources participate in the electricity grid. According to a 2017 survey, 65% of utilities rate distributed resource policy as ‘important’ or ‘very important’ to their company (Utility Dive and PA Consulting, 2017). This concern was second only to physical and cyber grid security. Given this climate, the goal of this project is to leverage data to describe what changes occur when utilities respond to the challenges of distributed resources with major electricity rate changes. We begin by taking a broad view of the rooftop solar policies in the US, including observations of rooftop PV market growth by state. We identify major policy events and select the case of Salt River Project in Arizona to investigate in more detail. Using the Tracking the Sun database, interviews, and simulations in System Advisor Model, we describe changes in PV adoption, PV system price, installer market, and system characteristics that coincide with a major rate design for Salt River Project solar customers.

## II. BROAD POLICY TRENDS IN ROOFTOP SOLAR

Solar power is rapidly becoming a viable energy solution for users in states across the country. The U.S. Department of Energy launched the SunShot Initiative in 2011 with the goal of aiding solar energy adoption through research and development efforts. The initiative laid the goal of improving solar affordability by driving down the price of residential, commercial, and utility-scale PV systems to levels that are cost-competitive with fossil fuel sources by 2020. Moreover, the Federal Solar Investment Tax Credit (ITC) was renewed in 2015 and is scheduled to remain at its current 30% level through 2019, before stepping down to 10% in 2020 and expiring in 2021 for residential users. The ITC is a 30% tax credit on solar systems for residential and commercial properties. After 2021, the ITC will remain permanently at 10% for commercial systems (Solar Energy Industries Association). As recent federal policies have favored the solar industry, a coinciding, although not necessarily correlated, upward trend in monthly small solar additions can be seen in Figure 1 below (this data source is described in Section III). Aside from short-term changes, there is no mistaking that residential solar installations have been on an upward climb. In 2014, residential PV system adoption increased by 66%. 2015 was another strong year, as PV was the fastest growing sector of the solar energy industry. Fourteen states exceeded 20 MW of new system capacity in 2015 alone (NC Clean Energy Tech Center, Oct. 2016).

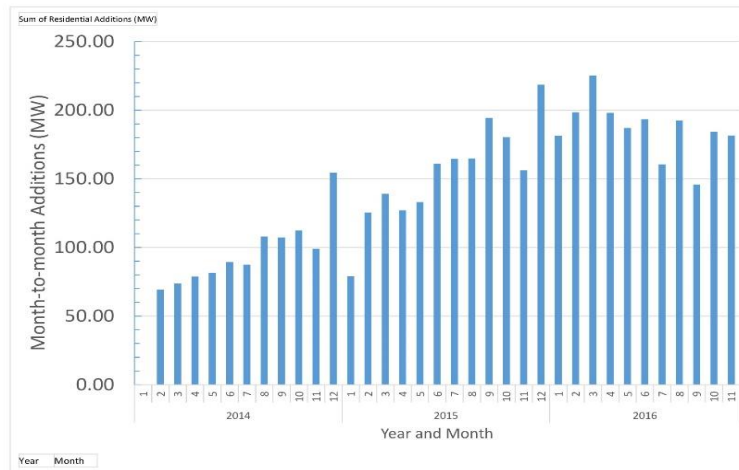


Figure 1: National small solar month-to-month additions (data source: EIA form 826 solar PV estimates, residential)

While adoption and pricing differ dramatically depending on state-level policy initiatives, overall both module and installation costs have fallen dramatically since 2009. These "soft costs," which include improvements in module efficiency and increases in system size, have continued to trend downward, despite relatively stable module costs since 2012 (Barbose & Darghouth, 2016). However, elimination or threats to state-level solar-friendly state policies, such as rebate programs and performance-based incentives, have tempered adoption by offsetting these major reductions in installation costs.

The electric industry is fundamentally changing from being a "one-way street" (utilities generate, transmit, and distribute solar to end users) to more of an interconnected web of users and providers. This shift has occurred so quickly that policymakers are struggling to keep pace, as current policy is designed around the "one-way street" paradigm (NC Clean Energy Tech Center, Apr. 2016). Questions over fair compensation to utilities and customers is at the heart of ongoing political debates over rate structures (NC Clean Energy Tech Center, Oct. 2016). States all over the country are taking a diverse approach to dealing with these questions, mainly focusing on net metering rules, tariff structures, and fixed costs incurred by PV system users, with net metering being the primary focus. This is important to the value of solar as the DOE estimates that elimination of net metering at utilities in six states would extend the payback period for residential distributed PV systems by between 1.4-8.9 years (Barbose et al., 2016). These policy debates between utilities and solar providers have continually increased in recent years, with 47 states and Washington D.C. taking some type of solar policy action in 2016; a total of 212 unique actions taken by states and utilities across the nation. 2016 saw 73 actions in 28 states on net metering alone; this is up from 42 actions in 2015. In the first quarter of 2016 alone, the North Carolina Clean Energy Technology Center catalogued 100 policy actions across the country, finding that 35 of those actions across 22 states related to policy changes in net metering. Beyond net metering, the first quarter of 2016 found that legislatures and public service commissions in nine states were considering changes to

the compensation schedule for real-time excess generation while seven states either ruled or were debating changes to aggregate caps for net metering capacity (NC Clean Energy Tech Center, Oct. 2016).

### III. 50 STATE ANALYSIS

For the analysis in this section, we utilize EIA form 826 data. EIA form 826 solar data is a sub-sample of data collected from all US utilities. The data provides generation and capacity by market sector for all small PV systems (<1 MW). We considered only the residential sector. EIA form 826 provides two useful sets of results: PV installation and net metering data. The net metering data has a broader scope (not limited to small solar), provides utility-level totals, and spans a longer time period. Generally, we found the two held the same trends at the state level. To make comparisons between states more meaningful, we normalized each state's installed capacity by its potential for rooftop PV capacity as per NREL 2016 (Gagnon et al. 2016). Hawaii was not included in this rooftop PV potential study so we estimated its potential at 3.7 MW.

All US states and Washington D.C. were surveyed using the EIA form 826 data, excluding Alaska. Regardless of the exact estimate of potential, Hawaii is in its own category for solar adoption, hovering around 10% of potential. Figure 2 provides a rough measure of the market maturity by dividing installed capacity in November 2016 EIA Form 826 by the estimated rooftop PV potential. The highest adoption levels are clustered in the southwest and northeast.

We began by conducting a detailed policy analysis of a starting list of 11 states with known, recent, policy changes. However, as potential ‘events’ were observed within the data, our investigations naturally expanded to include additional states. While policy changes may coincide with a visual change in a state’s technical potential capacity through Figures 3 – 6, this does not imply a correlation. After a broad overview of policy trends and change in capacity within several states, Section IV dives into more detailed analysis for the case study.

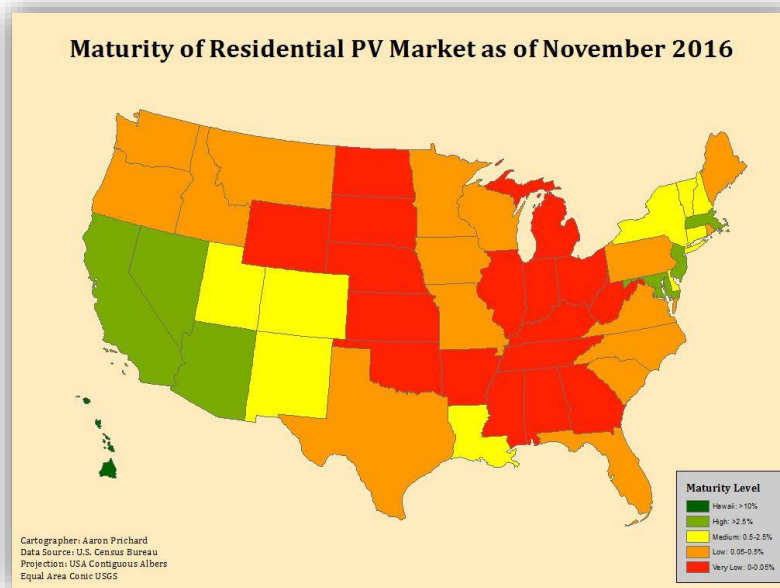


Figure 2: Residential solar market maturity (residential capacity installed / estimated capacity potential) based on November 2016 solar capacities from EIA form 826.

## TRENDS IN LOW-LEVEL SOLAR ADOPTER SELECTED STATES

### WISCONSIN, MINNESOTA, NORTH CAROLINA, MONTANA

While it is always important to research the leaders in the solar market, it is also beneficial to keep in mind that those states do not represent the majority at this point. Many of these states are not considered particularly innovative with regard to net metering or other favorable solar incentives, however, they represent the majority of U.S. states. This begs the question: how are the majority of U.S. states responding towards solar policy? Are their policies differing and if so, how? The states with low residential solar adoption are split into two figures: Figure 3 and Figure 4. Note that these states have penetration levels of less than 0.5%.

While some states have passed pro-solar policy changes, other states' policies have favored the interests of utility companies. For example, North Carolina's Duke Energy instituted a fixed charge increase from \$8 to \$19 in 2016, an event that affected rates paid by solar participants in the NC GreenPower performance-based incentive program. As of April 2016, that incentive program met a cap for 100 kW and smaller systems. Duke Energy has shown interest in eliminating net metering ever since its implementation in the state in 2005.

Wisconsin has also pursued an increase in charges, specifically through We Energies, which imposed a fee on existing solar generation. The case was eventually challenged in court and suspended in October 2015. We Energies' actions are part of a larger trend. In 2015 the Wisconsin Public Service Commission approved rate cases (including increases in fixed charges to customers) for three of the largest utilities in the state: We Energies, Wisconsin Public Service Corporation and Madison Gas & Electric. Moreover, the state changed how solar energy

production is counted on a customer's utility bill: from annual to monthly true-ups. As a whole, the state's most significant limitation to distributed generation in Wisconsin is a 20 kW system capacity limit for net metering programs.

As Wisconsin has continued to attempt to limit pro-solar policies within the state, Minnesota represents the other end of the policy spectrum. The state first turned a corner on net metering policy in 2013 with a round of legislation that increased the size limits of net metering policies for both IOUs and other power producers. In April 2014, the state public utilities commission passed a statewide value-of-solar formula as an optional alternative to net metering for utilities. This formula was intended to reflect a more complete value of solar generation not offered by avoided cost or retail rates. In September 2015, the final rules for the revised net metering policies were adopted by the state. In March 2015, Minnesota's PUC rejected Xcel Energy's request to increase residential monthly fixed charges from \$8 to \$9.25. Figure 3 demonstrates the results of these solar supportive policy changes; Minnesota surpassed Wisconsin in the percentage of eligible residences installing solar arrays.

There was an observed drop in PV capacity increase in the EIA data in January 2015 for Montana that did not appear in other years. The research team did not observe any policy-related events that would explain this phenomenon, but we observed several states experiencing the same trend at the time, which is not apparent in the January 2016 data. We consider single month-to-month changes like the one observed for Montana as anomalies.

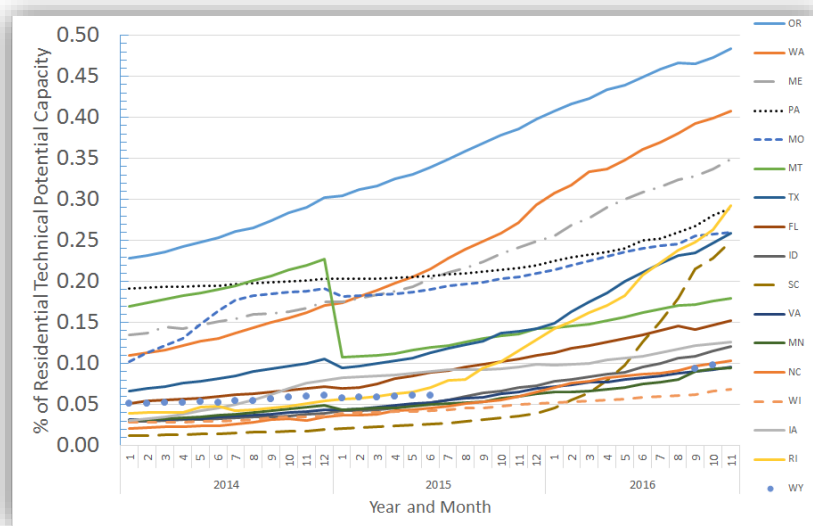


Figure 3: Low solar adoption state trends from EIA form 826 small solar estimates, residential.

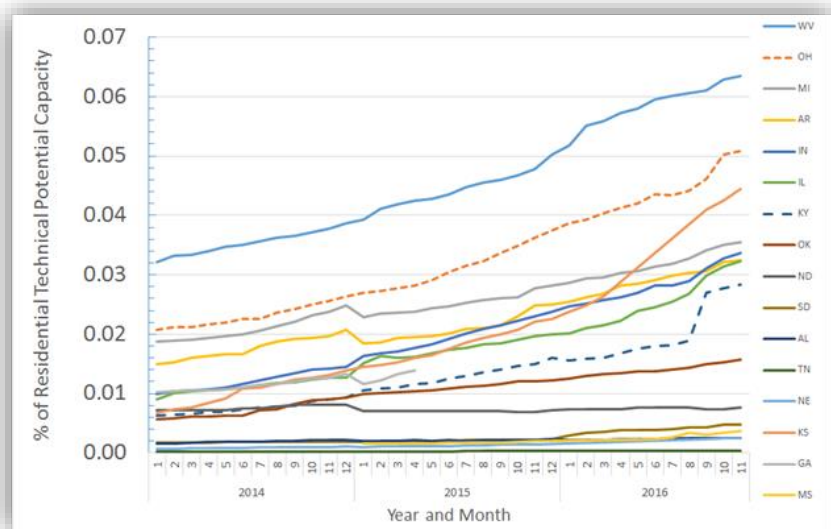


Figure 4: Very low solar adoption state trends from EIA form 826 small solar estimates, residential.

## TRENDS IN MID-LEVEL SOLAR ADOPTER SELECTED STATES

COLORADO, NEW YORK, NEW MEXICO, DELAWARE, CONNECTICUT

Mid-level solar adopter states have likewise witnessed a mixed bag of legislation and proposals in recent years. Decisions and policy changes have both benefited and hindered the solar industry in these states. The solar adoption trends are summarized for the mid-level solar adoption states in Figure 5. On the positive side of the spectrum sits Colorado, which has been considered the “golden child” of net metering by many industry experts. Their Solar Rewards program was first established in 2005 and reapproved in 2015 after a year-long consideration by their Public Utilities Commission. Figure 5 showcases a constant uptick in capacity, mirroring these policies.

New York has aggressively increased their policies favoring solar adoption, first in 2011 when they adopted remote net metering within the state, and again in 2012 when then-Governor Cuomo established the NY-Sun dynamic solar public-private partnership, committing \$1 billion over 10 years beginning in 2014. The ultimate goal of this project is to add 3 GW of solar by 2023 through the establishment of a variety of programs to encourage distributed solar systems. Beginning in 2014, the state’s capacity aggressively increased, surpassing other mid-level solar adopters.



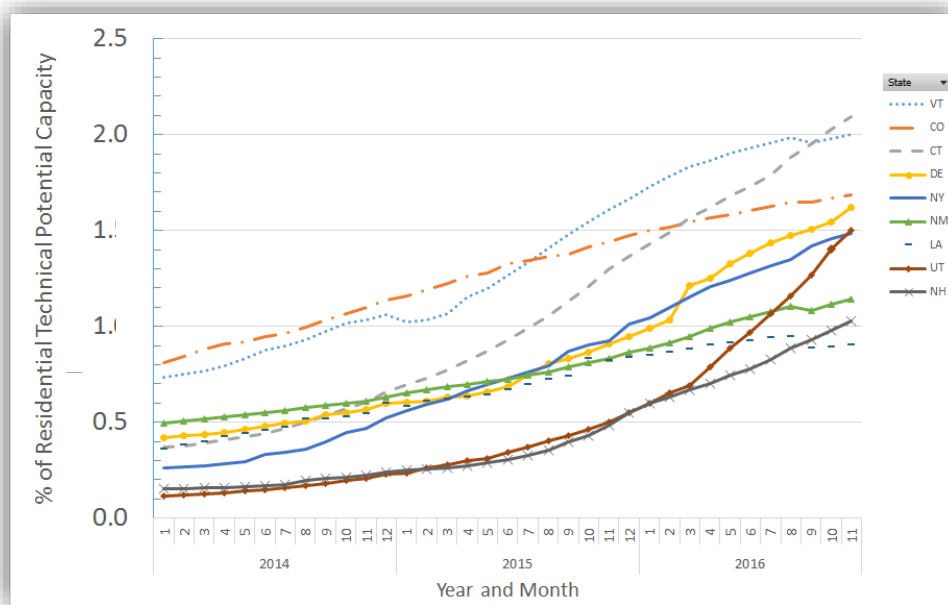


Figure 5: Mid-level solar adoption trends from EIA form 826 small solar estimates, residential.

Likewise, Connecticut has continued to focus on policies favoring solar; the Connecticut Public Utilities Regulatory Authority (PURA) ruled in November 2016 that United Illuminating would no longer cash out banked kWh's when customers switch suppliers. Suppliers will be required to reimburse customers for banked kWh's at the wholesale rate once the annual net metering period ends. Customers have the choice of two annual banking periods—April 1 and October 1, and suppliers are not required to serve net metering customers. PURA will make a final decision on this issue in August 2017.

A common trend across these states are attempts, both successful and unsuccessful, to introduce a variety of fixed costs and fees on solar net metered systems. Even in Colorado, the “golden child,” local IOU Xcel Energy proposed a new grid-use fee rate case in 2016. However, after public backlash, Xcel agreed to withdraw its case in exchange for the allowance of time-of-use rates.

Much like Colorado, Delaware represents an ongoing battle of this nature. Regulators are currently considering a decision to increase monthly fixed charges to residential customers; Delmarva Power & Light requested an increase from \$11.70 to \$17.47 per month. Since Delaware state law authorizes the public utility to implement temporary rate increases under specific conditions after a seven-month filing period with the public service commission. The interim rate increase was approved in December 2016, and a final ruling is still pending.

In recent years, New Mexico's utility companies have also proposed several changes to solar policies including interconnection fees, fixed charge increases, and increased charges for solar customers per kWh compared to other residential customers. While no such changes have been approved at this time, the state has seen an end in its tax credit program and much of its solar

production payment program across the state. The former's funding ran out as of mid-2016 while the latter payments had decreased from 13 cents/kWh in 2009 down to 2.5 by the end of 2015. While El Paso Electric chose to end this program in 2015, PNM was approved to extend the program for three years starting January 1<sup>st</sup>, 2017; the extended program applies to new interconnected systems only and will have a term of eight years with a purchase price of one quarter of a cent per kWh of energy produced and consumed on site, representing a fraction of what the program was 8 years prior. Figure 5 demonstrates a general leveling off of solar capacity growth in 2016 which aligns with the end of the state tax credit program for solar.

Only Connecticut saw a decrease in residential fixed charges from \$17.25 down to \$9.64 for United Illuminating after the utility had originally proposed an increase to \$18.74. PURA plans to review the customer charge for the next two years of the rate case as well, while also reviewing the state's net excess generation policies, when and how PV generated kWh's are accrued, banked, used, priced, and reimbursed, especially when customers change electric suppliers. Connecticut's Legislature barred customers who received solar rebates from taking advantage of net metering provisions in July 2014 in House Bill 5115 due to a transcription error. The decision was reversed following a major uproar from customers and solar industry officials, and the EIA 826 data did not show a related decrease in installations due to this error.

## TRENDS IN HIGH-LEVEL SOLAR ADOPTER SELECTED STATES

CALIFORNIA, HAWAII, ARIZONA, NEVADA, MASSACHUSETTS, D.C., MARYLAND

The solar adoption trends are reported as the percentage of residential technical capacity by month. Figure 6 illustrates the 2014 – 2016 monthly data for the highest solar adopter states. Hawaii is not shown but increases from 6% to 10% during the same period. Most states increase relatively continuously while DC and Nevada are notable and are discussed further below.

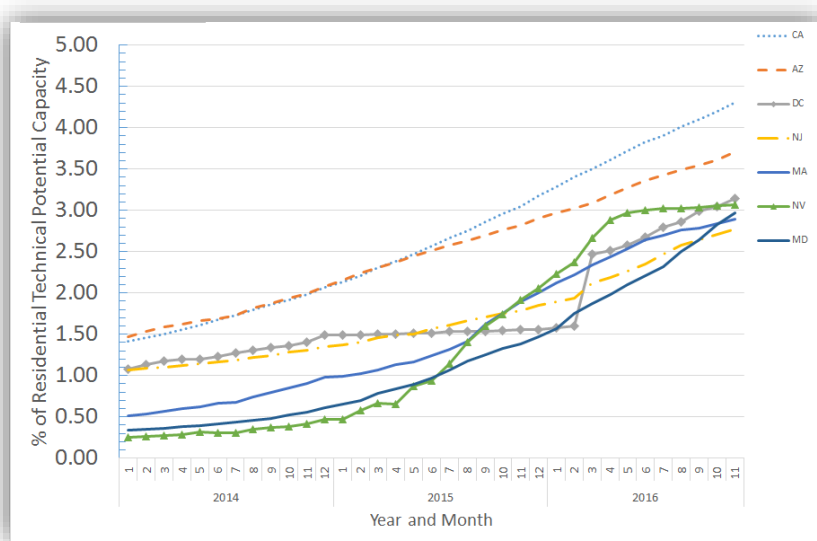


Figure 6: High solar adopters PV installations from EIA form 826 small solar estimates, residential.

The unique issue for high solar adopters, not yet present for mid and low-level adopter states, seems to be how to incorporate such a large rate of adoption into the grid without utilities feeling that the remaining supply, infrastructure, and other costs associated with such a high rate of solar adoption are inadvertently pushed onto non-solar customers. Hawaii and Nevada responded to this by effectively ending their net metering policies, while Arizona took a more moderate approach.

The first to confront the situation was Hawaii; roughly 17% of the customers of Hawaiian Electric, the state's dominant utility, have installed rooftop solar- the largest in the U.S. In 2015, the Hawaii Public Utilities Commission ruled to close Hawaiian Electric's net metering program for new participants. As a temporary replacement, 'self supply' and 'grid supply' tariffs were approved for newly integrating customers with the former using an expedited interconnection process while the latter option amounts to net billing. By mid-2016 the grid-connected option filled up and little interest has been shown in the 'self supply' option. Figure 7 shows the trends in monthly additions. Installations peaked in late 2015 and showed a decline by mid-2016 in line with the most attractive 'grid supply' option tariff not remaining available. A few months after Hawaii's action, Nevada also saw the end of its net metering program; in December 2015, the Public Utilities Commission of Nevada (PUCN) voted to end net metering within the state as commonly defined. Instead, beginning January 1st, 2016 customers were compensated for excess generation at the wholesale rate (net billing). Existing solar customers were scheduled to gradually phase into new tariffs through 2028. Figure 8 shows the monthly capacity additions for Nevada. One year after the Nevada decision, in December 2016, the Arizona Corporation Commission, which controls APS, TEP, and Unisource, after an extensive study on the value of solar, acted to replace the net metering that began in 2009 with compensation via an 'export rate' based on five-year averages of costs for large scale PV plants. By some estimates this number would be roughly 30% less than traditional retail rates, yet still a significant amount higher than net billing.

Both Nevada and Hawaii solar companies and advocates have fought these rulings. In Nevada, after severe backlash, the State District Court for Carson City overturned both the reduction in net metering compensation and increased fixed charges for existing rooftop solar customers, upholding the original changes for new rooftop solar customers. In December of 2016, the PUCN voted to restore net metering in NV Energy's Sierra Pacific Power Company's service territory for

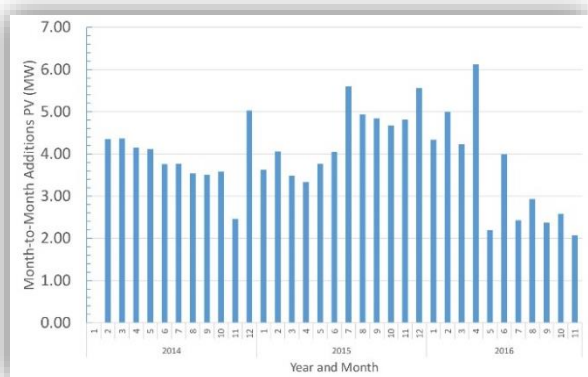


Figure 7: Hawaii month-to-month solar additions from EIA form 826 small solar estimates, residential.

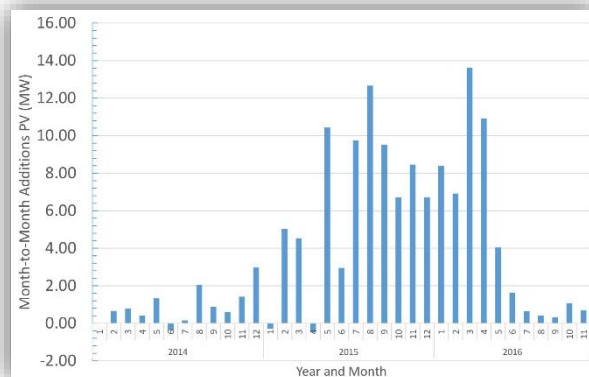


Figure 8: Nevada month-to-month solar additions from EIA form 826 small solar estimates, residential.

up to 6 megawatts of new rooftop solar (roughly 1,500 customers) beginning January 1, 2017. In Hawaii, conversely, no changes have been made to the existing interim policy. Solar companies have argued that they have been losing jobs and forced to downsize, citing a decrease in permitting applications of nearly 30% since August 2015. The solar community is demanding both an increase in the net billing caps as well as a permanent solution to the state's solar tariff program. The solar community waits for a more permanent solution to their net metering issues.

Some states saw the end of net metering while others saw expansions and revisions to their state policies. Washington D.C.'s Community Solar Renewable Energy Amendment Act of 2013 established a community net metering program which expanded the potential for net metering in the district<sup>1</sup>. In May of 2015, the PUC proposed its final amended set of rules, which allows third parties to own and operate community energy facilities up to 5 MW to be implemented 30 days after publication in the D.C. Register. However, the credit per kWh community solar participants would be receiving for excess generation was originally slated for 9 cents, compared to the 14 cents that rooftop solar customers receive. Solar advocates argued that this rate undervalued the electricity generated from community solar projects, making it difficult for such projects to be viable financially. In June 2016, the D.C. Council passed a bill restoring the price per kWh to 14 cents<sup>2</sup>. Massachusetts also took steps to expand its net metering program; the state's net metering caps were being reached through 2015-2016, there was a big push to increase allotment caps to allow for continued growth in the market. State-level policy was slow to react, but in April 2016 the state responded by introducing new caps, which were only incrementally higher and will likely reach their ceiling soon. An event study in Massachusetts might look like a series of mini-events, both increasing and decreasing solar installations as the caps are hit, then increased, then hit again in individual utility areas.

As D.C. and Massachusetts expanded their net metering programs, California saw the preservation of much of the state's net metering program after high profile proposals and debates throughout much of 2014 and 2015. In January 2017, the CPUC voted to preserve retail rate net metering with some alterations: a solar customers pay a one-time interconnection fee, pay non-bypassable charges per kWh consumed from the grid, and enter into a time-of-use rate schedule once established. Solar customers can be grandfathered into the tariff structure as it existed when they interconnected (for up to 20 years), or they can opt into the new tariff structure. The California Solar Energy Industries Association (CalSEIA) estimates that the aggregate financial increase due to these changes will be approximately \$10 per month when compared to the original policy.

Other common policy changes to the high-level solar adopters mainly consist of fixed charges. In October 2014, Maryland's Choptank Electric Cooperative filed a rate case application with the PSC to increase its residential monthly fixed charges from \$10 to \$17 and this was approved in March 2015. Also in December 2015, Nevada's PUCN approved an increase in fixed charges for solar customers above non-solar customers, from a \$5.15 difference in 2016 to a \$25.76 by 2028.

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<sup>1</sup> Maryland has taken similar steps to expand solar to low income communities; in April 2015, S.B 2010 was enacted which established a three year community solar pilot project. The goal of the project is to provide renewable energy benefits for low and moderate income customers. The project has not yet been enacted.

<sup>2</sup> While Figure 5 shows a sudden increase in solar additions in March of 2016, this appears to be an anomaly; every other month from 2014-2016 had less than 0.5 MW of new installations, there were 3.5 MW in the month of March 2016.

In California, a minimum bill concept (up to \$10) was approved as an alternative to utility requests for fixed monthly charges. California's CPUC also introduced a multi-year plan to incrementally flatten the state's four-tier utility rate structure to two by 2019.

Arizona policy has largely pursued utility-specific rate changes in recent years which allow analysts to study comparisons within the state based on utility service area. In 2013, the Arizona Public Service (APS) added a 70 cent charge per kW of solar system capacity effective November 2013. This equated to approximately \$5 per month for an average system size. In December 2014, Salt River Project (SRP)—a public utility that serves the Phoenix area—instituted a unique rate for new solar customers. The utility intended for existing solar and residential customers to see little to no change to their bills, while newly interconnected solar customers would witness a significant jump in their bill through an added peak demand charge, a fixed charge, along with a significant decrease (~60%) in energy rates. The projected change in price was an average of an increase of \$3 to \$5 for existing solar and residential customers and a \$50 average monthly increase for new solar customers applying after December 8<sup>th</sup>, 2014. The Arizona case, SRP in particular, is the focus of the next section of this project.

A drop in interconnection applications was immediately seen as illustrated by the *On the Path to Sunshot* report, when summarized on a quarterly basis using a separate dataset (not EIA Form 826). As shown in Figure 9, SRP's installation trend was different than the rest of the state. The remainder of this report focuses on the effect of this rate change in SRP territory.

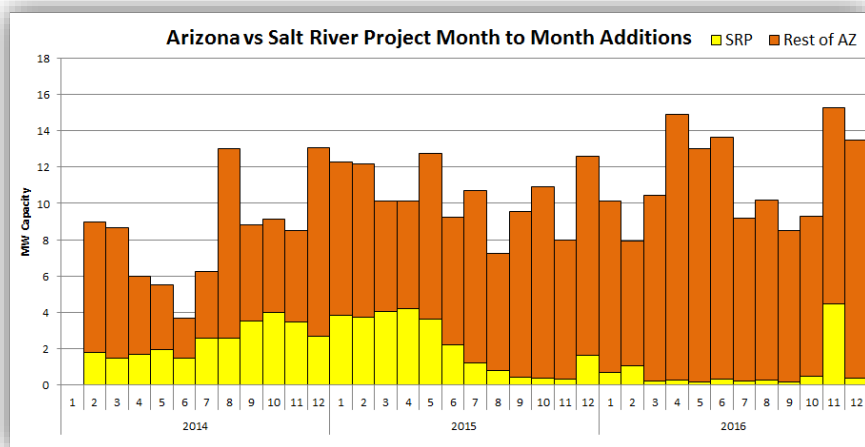


Figure 9: Salt River Project and other Arizona new PV capacity by month based on EIA 826 net metering data.

## IV. CASE STUDY: BACKGROUND

Salt River Project (SRP) created a unique rate plan, largely determined by demand-use fees and a fixed monthly charge applicable only to new self-generating solar customers; these changes went into effect during the April 2015 billing cycle. As the above section highlights, early numbers seem to indicate that interconnection applications dropped almost immediately after the change went into effect. It is important to note that the rate change itself was not approved until February of 2015. However, customers who applied for solar interconnection by December 8<sup>th</sup> 2014 were grandfathered in to the previous rate as it existed prior to the change. SRP initially informed its customers of this deadline by letter on November 29<sup>th</sup>, 2014 (personal communication, SRP Solar Department, May 6<sup>th</sup>, 2017). Among other reasons to be expanded upon below, the relative suddenness of this rate change makes this scenario a good candidate for a case study, even more so because a neighboring utility—APS, serves as a useful benchmark for business-as-usual in Phoenix during the same time period. This section describes both utilities and the SRP rate change.

### SALT RIVER PROJECT (SRP) AND ARIZONA PUBLIC SERVICE (APS) BACKGROUND

Salt River Project (SRP) is a water and electric district in central Arizona. It is a public utility that delivers water and electricity within the district, which is mainly comprised of the Phoenix area. In fact, SRP was founded a decade before Arizona itself became a state; it was founded as settlers in the area realized they needed to work together to build and maintain water storage and delivery systems to support the agricultural projects in the area. From those beginnings, it eventually became a publicly-owned utility with governance conducted through an elected board in which votes are cast by landowners in the utility service territory.

APS borders SRP primarily to the west and southwest, and services most of the remaining customers in the Phoenix area (Figure 10). While SRP largely services the city itself, APS serves a much larger part of Arizona, both rural and urban. While SRP is publicly-owned, APS is an investor-owned utility and thus is regulated by the Arizona Corporation Commission along with other utilities including the other major electric utility of Tucson Electric Power (TEP). In utilizing APS as a comparison for our SRP case study, the research team elected to focus exclusively on Maricopa County, which essentially includes all of metropolitan Phoenix.

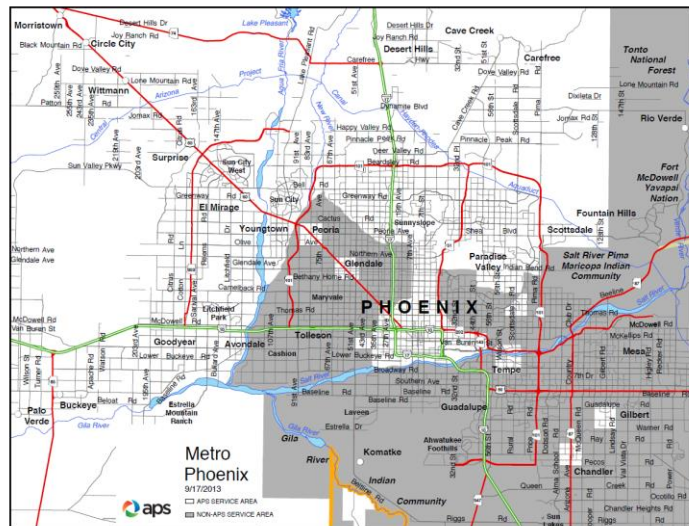


Figure 10: APS service territory map for the Phoenix metro area. Non-APS service area is largely SRP's territory. From APS: [https://www.aps.com/library/communications1/PHX\\_Map.pdf](https://www.aps.com/library/communications1/PHX_Map.pdf).



## RATIONALE FOR THE RATE CHANGE

Under the standard residential plan (E-23), solar connected customers' monthly bills are reduced in proportion to their reduced energy usage (kWh); the average SRP rate customer was paying \$170 per month, while solar net metering customers were paying \$70, saving an average of \$100 each month. However, SRP argued that monthly bills should account for both energy use and demand, pointing out that solar customers' peak demand only decreased from 8.9kW to 8.5kW. This is likely a result of natural limits of solar production; as sunlight and therefore, solar energy generation, fades in the afternoon, causing typical solar customers to ease back onto grid energy. However, because this transition occurs under peak energy demand hours, solar customers are still utilizing the grid system during peak demand use. Their arguments have been represented in Figures 11 and 12.

SRP argued that since solar customers' demand did not decrease in proportion to their energy use, and because those same customers continued to utilize the grid during peak demand, they must therefore financially contribute more despite their decrease in energy use otherwise. In fact, over 70% of SRP's own costs are fixed, and they argued that solar customers are not paying their fair portion toward those costs, which include maintenance of system infrastructure, the size of which is based on peak demand. Of the \$100 savings that solar-connected customers reaped each month, the actual amount of *avoided* costs seen by SRP represented only half of this savings (\$50), leaving a net revenue loss of \$50 per solar customer. SRP argued in December 2014 that they were under-collecting roughly \$9 million from their solar connected customers, which they said would be unfairly passed onto their non-solar customers if nothing was changed.

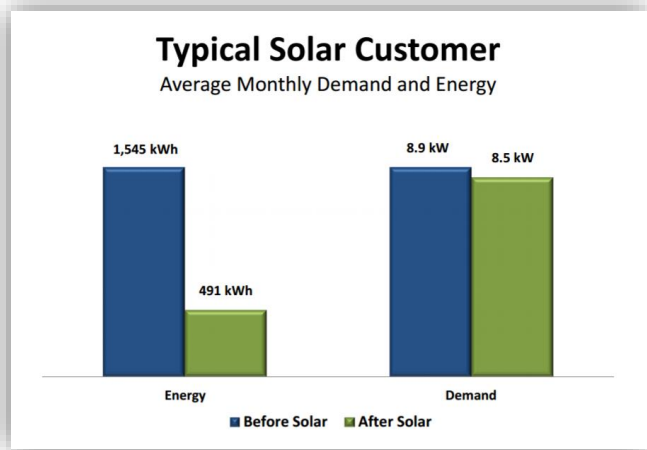


Figure 12: Credit: [SRP Feb. 12<sup>th</sup> 2015 Presentation](#)

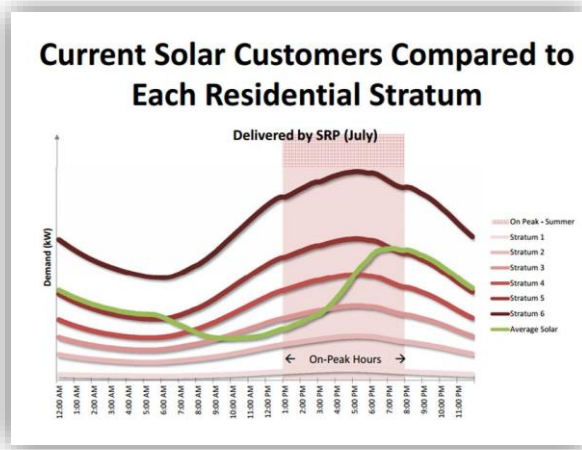


Figure 11: Credit: [SRP Feb. 12<sup>th</sup> 2015 Presentation](#)

While SRP made arguments for why this rate change was necessary, it is important to note that to date, more than a dozen states have conducted studies on the costs and benefits of distributed solar and none have found any evidence of a net negative impact on non-solar customers. Yet, utilities like SRP continue to advocate for rate changes to their distributed energy solar policies as adoption continues to increase. In February 2016, the Arizona Public Commission released their own updated state report on the costs and benefits of distributed solar.

## THE RATE CHANGE

SRP voted to implement a rate increase for its solar-connected utility customers. The net goal of this was for existing SRP customers, including solar customers, to see little to no change on their monthly bills. However, solar customers that applied for interconnection after December 8<sup>th</sup>, 2014, must connect to the grid under SRP's new Customer Generation Price Plan (E-27). In this plan, the energy charge is about half the rate of the utility's time of use (TOU) plan and is the lowest rate of any residential plan. Added is a per kW demand charge as well as a monthly service charge of \$32.44 to help offset the cost of grid maintenance and infrastructure.

### Details from SRP E-27 price plan

#### CUSTOMER GENERATION PRICE PLAN FOR RESIDENTIAL SERVICE

*Participation in this plan is required for all such customers, except for those customers who originally **installed the on-site generation at a residence on or before December 8, 2014**, or who (i) by such date, either delivered to SRP a **fully-executed contract** for the installation of the on-site generation or had an **SRP Residential Solar Electric Program Application** for the on-site generation pending with SRP, and (ii) interconnect the generating facility with SRP's electrical grid by February 26, 2016. If a customer meets this exception, that customer will be exempt from required participation in this plan...*

Under the new price plan, SRP argued that the average solar customer would still see a drop in their monthly bill, but it would still allow for the collection of enough funds to cover infrastructure maintenance and costs. If the average solar customer changed nothing about their habits, they would still be able to see a drop in their bill by \$50 per month from the average starting point of \$170. However, SRP has done a lot of work to promote changes in behavior to reduce demand charges. By utilizing batteries, shifting energy use to non-peak hours, managing home energy use so major appliances aren't running simultaneously, making sure panels are west-facing, adopting new technology like load controllers or smart thermostats or simply changing behavior to respond to the changed price signals, customers can see a savings of up to \$100 per month, double the amount the solar installation alone can offer.

Table 1: SRP Price Plans' Costs and Revenues

	E-23 Non Solar	E-23 Grandfathered Solar Customer	E-27 New Solar Customers
<b>Average Monthly Bill</b>	\$170	\$70	\$120 <sup>3</sup>
<b>SRP Avoided Costs</b>	-	\$50	\$50
<b>Revenue Loss</b>	-	\$50	None

<sup>3</sup> Per SRP Predictions



This new price plan, E-27, introduces new demand charges instead of a simple pay per kWh alternative. This demand charge is based on peak demand use during peak periods which range from 5am – 9am and 5pm – 9pm in the winter months to 1pm – 8pm during the summer months. If nothing else of the customer’s behavior changes, the average demand was, as stated above, 8.5kW would translate to a demand charge of roughly \$42 during winter months, \$105 during summer months, and \$127 during summer peak hours. Taking into account the fixed monthly charge of \$32.44, this can represent a large ‘fixed portion’ of any solar customer’s bill, assuming no behavioral changes take place.



Figure 13: Demand charge schedule for SRP self-generating customers after December 8<sup>th</sup>, 2014.  
Credit: [US Utility Rate Database](#)

Table 2: On-Peak Demand Charges (per kW) under SRP E-27 Price Plan Credit: SRP

On-peak demand charges (per kW)			
	First 3 kW	Next 7 kW	All add'l KW
WINTER (Nov.-April)	\$3.55	\$5.68	\$9.74
SUMMER (May-June and Sept.-Oct.)	\$8.03	\$14.63	\$27.77
SUMMER PEAK (July-Aug.)	\$9.59	\$17.82	\$34.19

However, while there are introduced demand charges and a higher fixed charge each month, newly connected solar customers can benefit from a substantially reduced price for kWh of energy used each month. As stated by SRP above, their average residential customer uses 1,545 kWh of energy each month while the average solar customer uses 491 kWh. Utilizing these averages, under E-27, the cost of energy ranges from \$21 in winter months to \$31 during summer peak months. In contrast, under the traditional E-23 pricing plane, energy use would cost \$123 in the winter months and \$179 during summer peak months. These numbers help to demonstrate that the E-27 pricing plan is heavily focused on demand use during peak hours; in fact, most of the charges solar customers see on their bills is a combination of these demand charges in conjunction with the fixed monthly charge. Therefore, to truly reap the benefits of installing solar under SRP's E-27 plan, customer's almost *must* take steps to modify their energy use behavior.

Table 3: Per kWh Energy Charges for SRP Customers on E-27 and E-23 Price Plans in Cents

		Winter (Nov-April)	Summer (May-June & Sep-Oct)	Summer Peak (July-Aug)
<b>E-27</b>	Off Peak	3.86	3.67	4.19
	On Peak	4.26	4.82	6.29
<b>E-23</b>	First 700kWh	7.93	10.82	11.48
	701-2000kWh	7.93	11.01	11.60
	2001kWh+	7.93	12.96	13.11

## V. CASE STUDY: EFFECTS OF THE SRP RATE CHANGE

This section outlines how the Tracking the Sun (TSS) database, interviews, and System Advisor Model (SAM) simulations were used to understand effects of the SRP rate change.

### METHODS AND DATA

In an effort to better focus our event study, we sought to limit the data to ensure a fair analysis of the policy on local solar installations. First, we sought to compare Arizona Public Service and the Salt River Project service territories limiting the data search to Maricopa County i.e. the greater Phoenix area (Figure 15). Next, we eliminated any data where the system size was smaller than 1 kW or larger than 15 kW in account for residential systems. Systems with an appraised were eliminated for price analysis. In addition, if installation price was not listed (value of -9999), the entry was eliminated for price analysis.

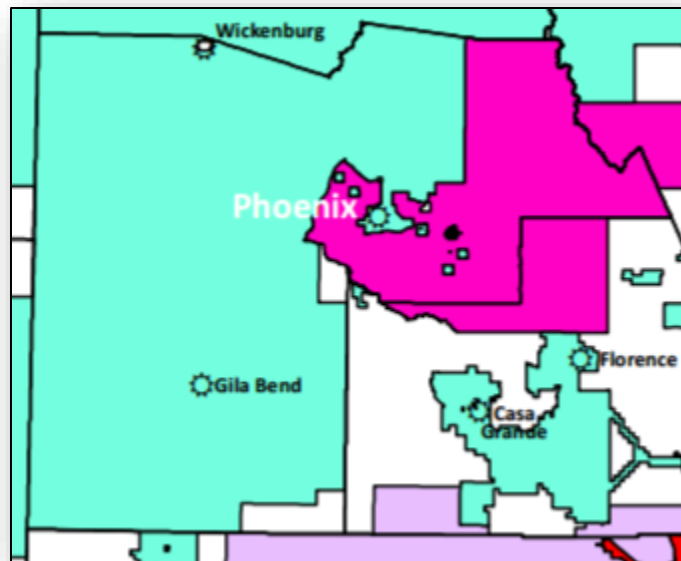


Figure 14 : Utility service territory for Maricopa County, Arizona. Source: Arizona Corporation Commission Utilities Division—Engineering Section/GIS Mapping.

Data analysis focused on projects installed in 2014 and 2015. There were 18,659 observations after removing data that did not meet screening criteria. Of these, 12,565 were for APS and 6,094 were for SRP for the 2014-2015 installations. This section provides summary information about the data. Figure 15 shows the project breakdown based on ownership (third-party ownership or not) and price flag (appraised or not). Overall system size and cost per kW were similar, making a case for the comparison of these two markets (Figures 16 & 17). The SRP projects in this period tended to be a bit smaller and their cost per kW was slightly higher.

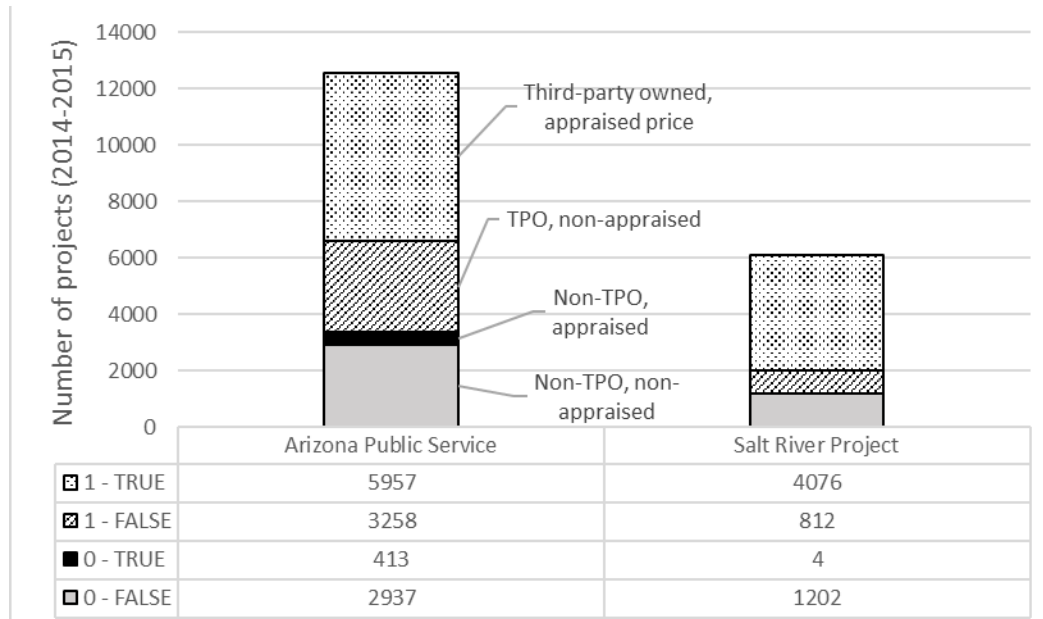


Figure 15: The 2014-2015 dataset had a majority of projects from third-party-owned systems. Many of the third-party owned projects had appraised prices.

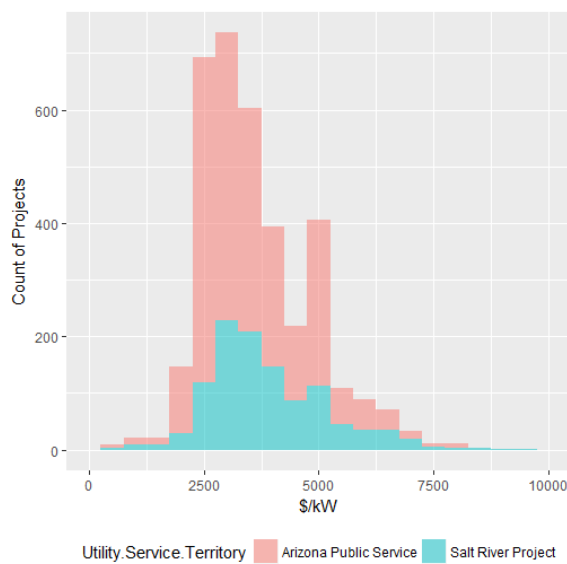


Figure 17: Comparison of Price per kW after removing unpriced, third-party, and appraised value systems. The price per kW in the dataset was slightly higher in SRP (\$3,912/kW) than APS (\$3,588/kW). The difference was significant with  $p=7e-11$ . A 95% confidence interval for the difference in means was \$227-421 per kW.

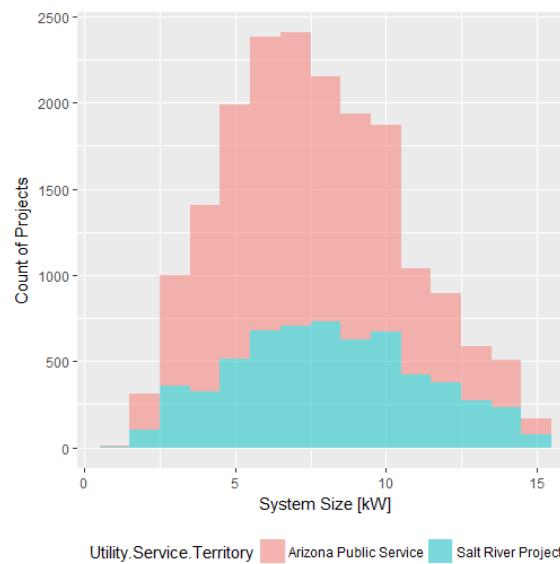


Figure 16: Comparison of System Size: The system size in full the dataset was higher lower in SRP (8.2 kW) than APS (7.5 kW). The difference was significant with  $p=2e-16$ . A 95% confidence interval for the difference in means was 0.6 – 0.8 kW.

To study solar adoption trends over time and quantify the impact of the rate change, it was important to distinguish between application date and installation date. These fields are reported differently for each utility in the TTS dataset, but in comparing SRP & APS, the time from application to installation in the two year data set was about the same (Table 4). There is some temporal variation in the installation delay, especially around the SRP event as customers applying in December 2014 on average delayed 175 days (Figure 18).

Table 4: Average time from application to installations.

SRP	APS	Both
112 days	92 days	98 days

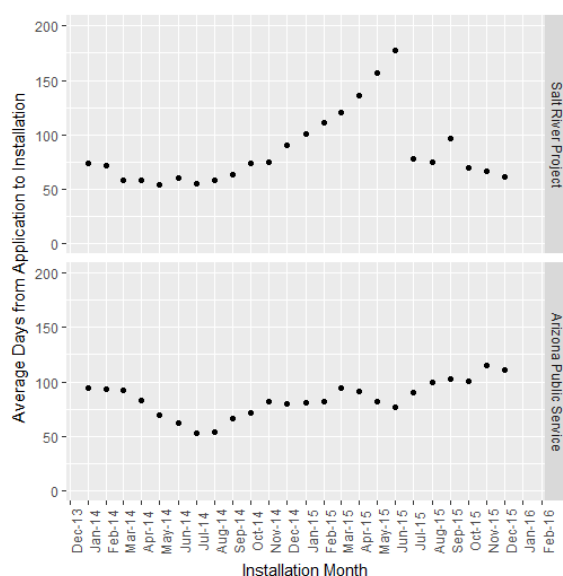


Figure 18: Number of days from application to installation by month of installation.

## BROAD MARKET CHANGES

Since the rate change has went into effect, there have been drastic market changes and attempts to adapt (Personal Communication, American Roofing and Solar, April 2017)<sup>4</sup>. Joy Seitz, president and CEO of American Solar and Roofing confirms this sentiment, stating that while the rate change won't end solar roofing in Arizona, this decision will require solar companies to make adaptations. "This change sends a signal that future residential solar offerings will require complementary technologies that maximize self-consumption, such as storage and load management [and] when these technologies are implemented in conjunction with optimally sited solar, all ratepayers will benefit from peak demand reduction." (Pyper, 2016)

<sup>4</sup> While we were unable to reach Solar City for comments, American Roofing and Solar was more than willing to discuss how the rate change has, and continues to affect how they conduct business with customers in SRP territory. A multitude of phone conversations took place with the company's solar installers over the course of April – May 2017.

A representative installer of the company discussed specifically how the market has changed for them since the start of 2015 (Personal Communications, American Roofing and Solar, May 2017). First and foremost, they will almost only quote customers that are able to do a west facing roof. This allows them to create energy until slightly later in the day to offset using the expensive energy during peak demand time. This contrasts with the traditional notion of utilizing south-facing roofs which will generate the maximum amount of energy throughout the year. However, searching ways to ensure customers a savings financially, focusing on west facing roofs quickly became a necessity.

Moreover, both they and their competitors have implanted different types of load controllers into their systems. For example, some solar installers such as Sun Valley have chosen to install load controllers into air conditioning units to monitor demand load at any given time and if the customer is approaching a certain level of demand use, the load controller acts as a kill switch to prevent this from occurring. American Solar and Roofing also utilizes load controllers; however, theirs do not act as a kill switch but instead alert you when you are approaching a certain level of demand; it becomes up to the customer themselves to actively turn off air conditioning, washers, driers, dishwashers, etc. if they want to avoid increasing their demand fees. On their load controllers, Sun Valley CEO Russ Patzer stated, “Our whole point is we want something the customer doesn’t have to think about. They don’t have to have a comfort change or lifestyle change.” (Randazzo, 2016)

While load controllers are becoming almost mandatory in SRP territory, Patzer also said that they don’t typically install as many panels on a home as they used to prior to the rate change. This is because customers just aren’t rewarded as much for producing large quantities of excess energy. The Tracking the Sun database confirms this, showing an average system size of 8.2 kW for systems on the old rate. In contrast, of installations under the new pricing plan, the average system size was 6.7 kW (Table 5).

*Table 5: System Size for SRP under old and new rates.*

	<b>Average system size</b>	<b>Percentage of projects third-party owned</b>	<b>Number of projects (2014-2015)</b>
<b>E-23 (old rate)</b>	8.2	82%	5,928
<b>E-27 (new rate)</b>	6.7	2%	166

While some solar installers are attempting to respond to the market changes caused by this rate change, others are exiting the market entirely. For example, SRP’s manager of pricing design, John Tucker, explained that prior to SRP’s rate change to E-27, 75% of solar installations in SRP territory were through a solar leasing option, and confirmed that since the rate change went into effect, this number has dropped to 25% (Randazzo, 2016). After the rate change, it has become more difficult to promise any type of savings worthwhile for the customer (leasing or otherwise) without dramatic behavioral changes (Personal Communications, American Solar and Roofing, April 2017). SolarCity, the nation’s largest leasing company, has largely left the area altogether (Randazzo, 2016).

SolarCity has also found themselves in a legal battle with SRP over the rate change. They have accused SRP of “anticompetitive and tortious conduct designed to eliminate solar competition.” The company’s complaint against SRP stated that they believe that “SRP’s penalty on solar

customers is harmful to consumers, and harmful to competition," adding that "competition is eliminated, consumers are hurt, and the environment is harmed (SolarCity, 2015)."

The Tracking the Sun data confirmed that third-party owned projects are much less common under the new rate. Figure 19 shows applications by third-party ownership (TPO) and utility. The December 8<sup>th</sup> event impact on TPO projects in SRP is evident. Overall we found that 82% of SRP customers on the old rate were third-party projects, while only 2% of projects on the new rate were third-party owned through 2015 (Table 5). (As a point of comparison, 72% of the APS projects were third-party owned.)

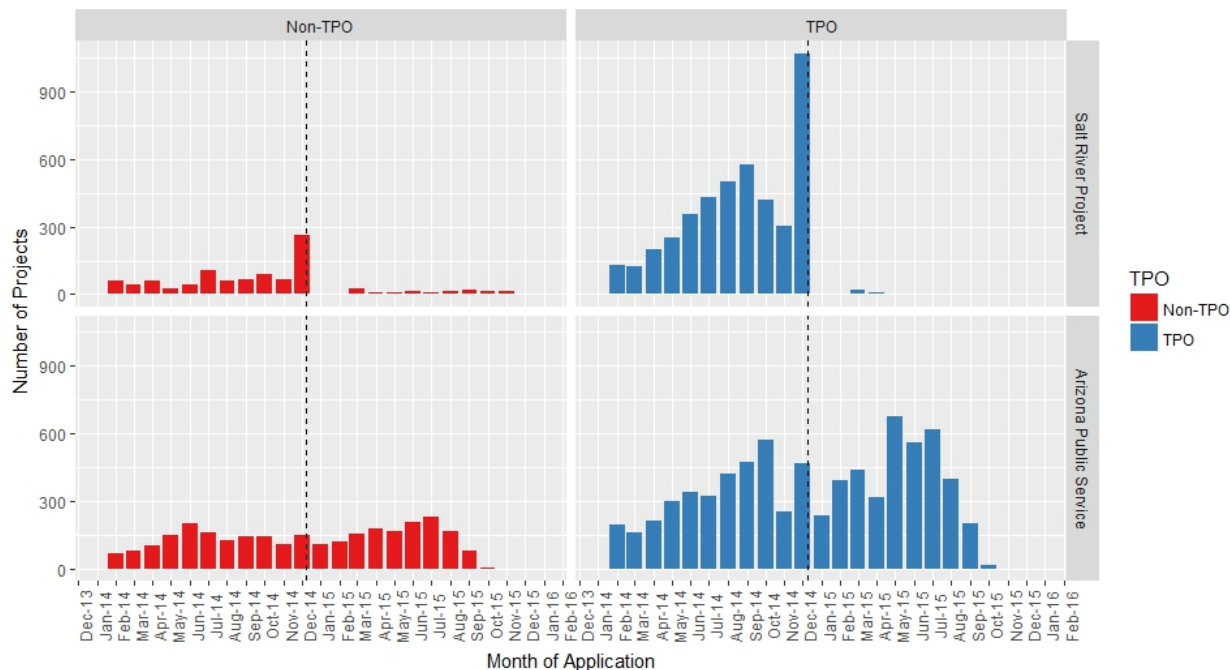


Figure 19: Applications by month for third party and non-third party owned projects for SRP and APS territories. Third party projects are eliminated in SRP territory shortly after the event; no such trend is visible in APS.

Changes in the installer market are also analyzed using the TTS dataset for 2014-2015. Figures 20-21 show that the market moves toward more, smaller installers. Under the new rate the market is dominated by small installers who install less than 2% of all total projects, identified as "Others". Figure 22 provides a monthly view of the SRP installer market. The number of projects per installer decreases, while in Figure 23 the APS trend is steady or increasing.

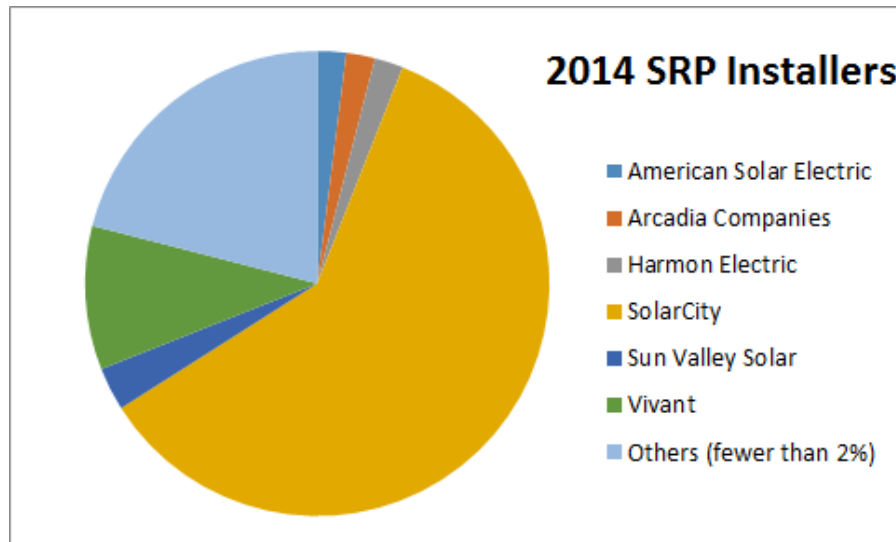


Figure 20: Installers by number of projects under the old rate (application date in 2014).

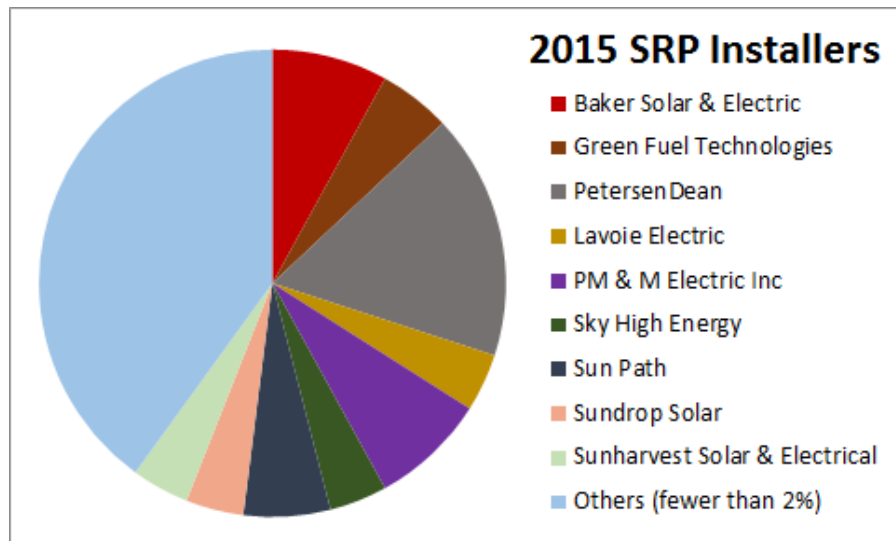


Figure 21: Installers by number of projects under the new rate (application date in 2015).



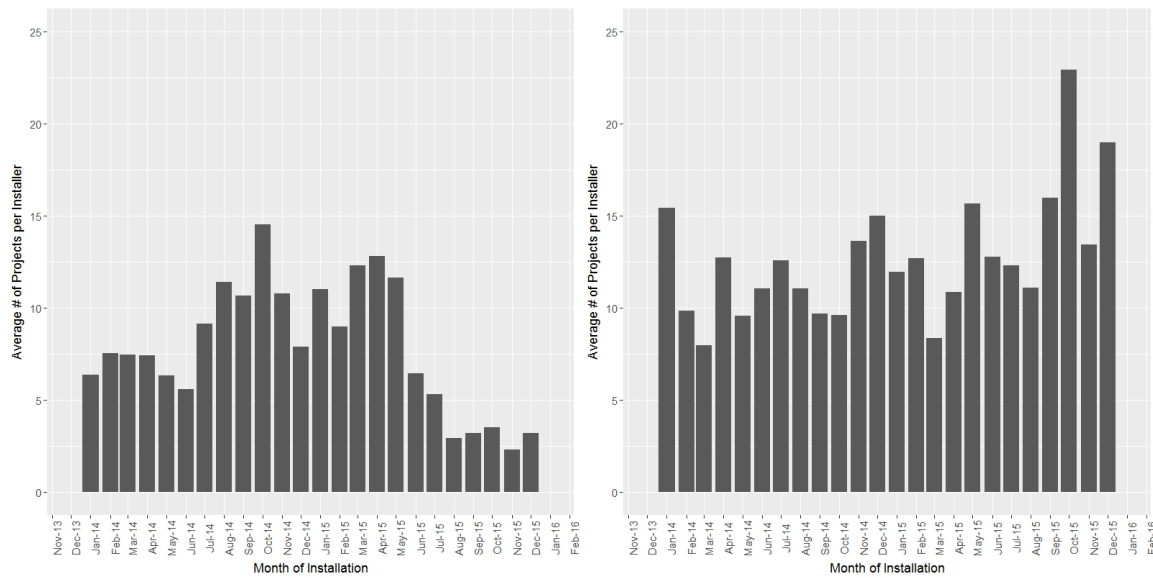


Figure 22: (Left) SRP average number of projects per installer each month shows decline in activity. The number of projects installed each month is divided by the number of installers active that month (at least one project).

Figure 23: (Right) APS average number of projects per installer each month shows relatively steady to increasing activity.

## SOLAR-PLUS-STORAGE & OTHER BEHAVIOR CHANGES

SRP argued from the onset that if customers were to change behavior on when they utilized electricity from the grid and how they utilized it, they could reap benefits far beyond the \$50 per month under the new rate plan. SRP has campaigned heavily on the promotion of behavioral changes to fully take advantage of the benefits of this pricing plan. A quick glance through their website’s solar section showcases this in the form of text, infographics, and videos. Offering suggestions, SRP Treasurer and Financial Services Director Steve Hulet stated that “the customer can adopt new technology, whether it’s load controllers or smart thermostats or battery technology, and change their behavior to respond to those price signals.” (Trabish, 2015)

One of the more common changes SRP suggested was the utilization of batteries, or solar-plus-storage. In fact, the solar community agrees with this argument that demand charges will drive solar plus storage technologies- despite the current economics of doing so. Ravi Manghani, GTM Research energy storage analyst when interviewed, stated that, “Any kind of net energy metering reform that reduces the value of solar works in favor of storage.” (Trabish, 2015) A recent GTM research analysis found that a potential SRP residential customer with a demand charge hovering around \$32 with a 4kW system would result in solar plus storage being financially superior to solar alone. As showcased above, without any behavioral changes, the average SRP solar customer maintains a peak demand energy use of 8.5 kW, translating to a demand charge above the \$32 benchmark, thus making solar-plus-storage a viable option under GTM’s analysis.

The Tracking the Sun (TTS) dataset listed nine battery systems installed in our case study area of the 5,928 projects under the old rate plan. This shows that solar alone was the more financially

viable option under those conditions. After E-27 took effect, two battery solar systems were reported by TTS of the 166 projects under the new rate. Thus the 2014-2015 data set does not show strong adoption of storage.

Installers for American Solar and Roofing out of Phoenix confirmed that behavior changes and add-ons are necessary after the rate change to ensure the financial savings associated with rooftop panels (Personal Communication, American Roofing and Solar, April 2017). While installers have heard some news of Tesla batteries in the area, American Solar and Roofing has yet to roll out battery usage in their systems, hoping to get them out by the end of 2017 with new installations. The company's plan is to first kick out battery usage on west facing roofs with solar for use when solar production largely diminishes (around 6:30 pm). The battery's storage would then be used during the remaining peak hours (6:30-8pm in the summer) to help minimize massive behavioral changes in energy use by customers. Once peak hours end, the battery would use cheap grid energy to recharge so the customer is able to avoid paying large demand costs. These battery systems could also bring potential back to the installations of south facing panels, simply being used for a longer time period during said peak hours: 5:30-8pm in the summer, for example.

American Roofing and Solar's perspective coincides with the premises that the process of widely rolling out batteries is a somewhat slower one, seeming to be slower changing, more long term effect on the solar market. To note, Manghani also made the point that "SRP is only one utility out of the 3,000 in the U.S. but it will not be the last utility to enforce a residential rate structure that benefits solar-plus-storage (Trabish, 2015)." As more and more utilities continue to make changes to their rate structures through demand charges, fixed charges, TOU rate structures, or reduced net metering rates, solar-plus-storage will likely become more economical, and thus more widely implemented in the years to come.

In fact, *The Economics of Load Defection*, published in early 2015 found that as energy prices continue to rise, battery prices continue to fall, and technology costs continue to rapidly evolve, solar-plus-storage options will become increasingly economically viable options for the average solar residential consumer. The authors conclude that within 15 years, such systems will saturate many important markets within the United States including New York, California, Hawaii, Kentucky, and Texas (Bronski et al, 2015). It will be important to look back at the use of batteries on SRP solar systems in the years after 2015.

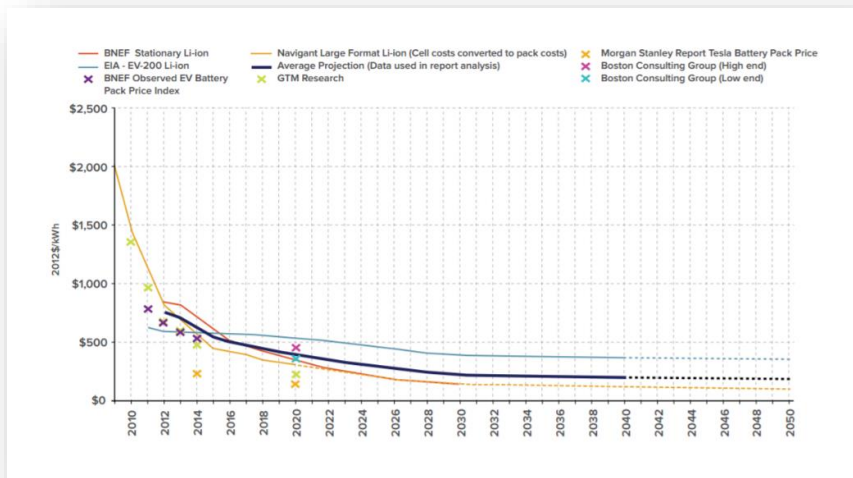


Figure 24: Battery price trends Credit: *The Economics of Load Defection*, 2015

## SYSTEM ADVISOR MODEL (SAM) SNAPSHOT: 2014 VS. 2015

Using System Advisor Model, we chose to portray the average SRP customer under the old rate plan with a rooftop solar system and then compare this to the average SRP customer that would have installed rooftop solar after the rate E-27 went into effect. We went in wanting to change many variables including system size, utility rate schedule, module, and inverter used. However, both the most widely used inverter and module, according to TTS data, were the same both years. Moreover, while the system size decreased from 8.2kW down to 6.7kW under the new rate plan, we chose to keep this constant for better financial comparisons. In the 2015 scenario, we also did input a change in azimuth angle as many installers were quick to point that they almost exclusively will only install panels on west-facing roofs to assist in energy production later in the day. This varies from prior to the rate change, where south facing roofs were ideal for total year-round energy production. The general results of the simulation are listed in Table 6.

As shown in Figures 27 and 28, the energy production of these systems is drastically different, in fact the annual production decreases by almost 2,000 kWh. However, by changing the azimuth angle back to south facing even after the rate change, you can see why west-facing systems have become almost a necessity. This is even further detailed in Figure 26 showing that while south-facing systems will produce more energy during the day overall, west-facing systems will produce energy slightly later in the day, which will help reduce demand charges during peak summer periods under the new rate plan (E-27). This contrasts with maintaining the use of a south-facing system even under the new rate plan. In this case, while the annual energy production is essentially the same as a system prior to the rate change, the payback period jumps to 19.9 years and the net present value to \$-4,291. This is solely due to the costs of a higher demand charges during peak energy use times instituted by E-27. In fact, if you assume that the rate change would cause a \$50 per month increase in energy bills, over the lifetime of a rooftop solar system, this could mean a net change in \$50 by 12 months each year by 20 years, or a total difference of \$12,000. These payback period differences between, west and south facing systems pre and post event are also further illustrated in Figure 25.

Table 6: System Advisor Model Results

SAM Variables Altered			
	2014 Pre-Event (E-23) South Facing Panels	2015 Post Event (E-27) West Facing Panels	2015 Post Event (E-27) South Facing Panels
<b>Annual Energy Production (Year 1)</b>	10,113 kWh	8,434 kWh	10,113kWh
<b>Net Present Value</b>	\$865	\$-2,941	\$-4,281
<b>Payback Period</b>	10.9 years	17.3 years	19.9 years

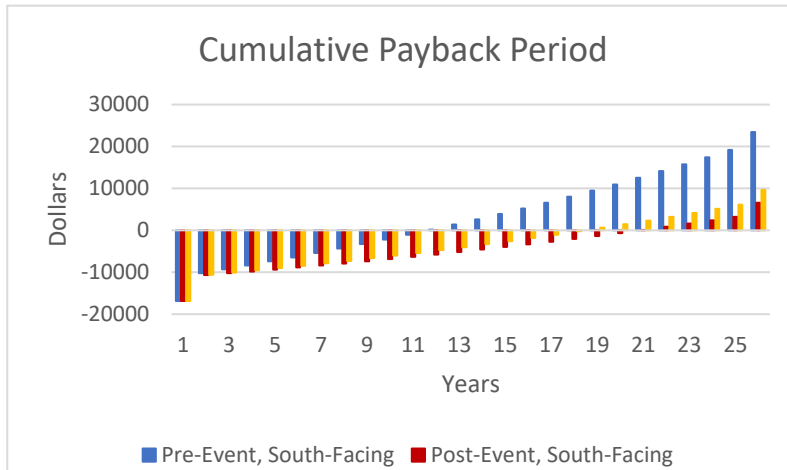


Figure 25: Payback Periods of 6.5kW System Using System Advisor Model

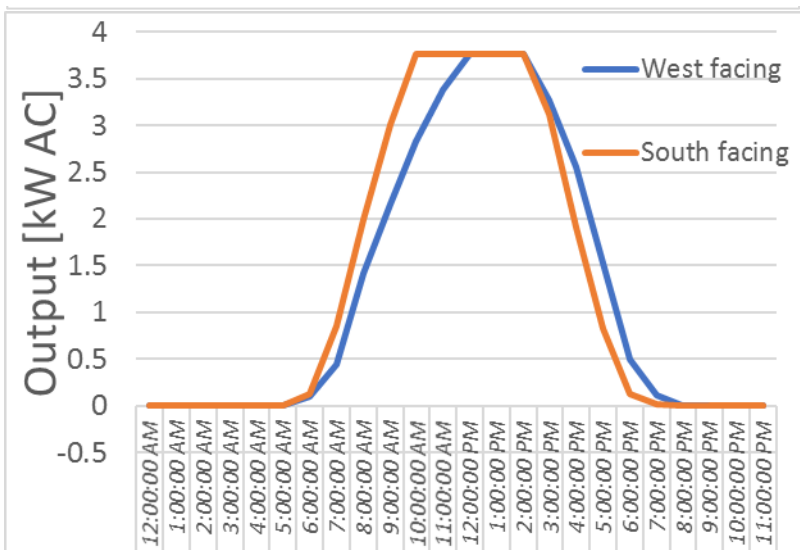


Figure 26: Energy Production on a July Day for a 6.5kW West and South-Facing System Using System Advisor Model

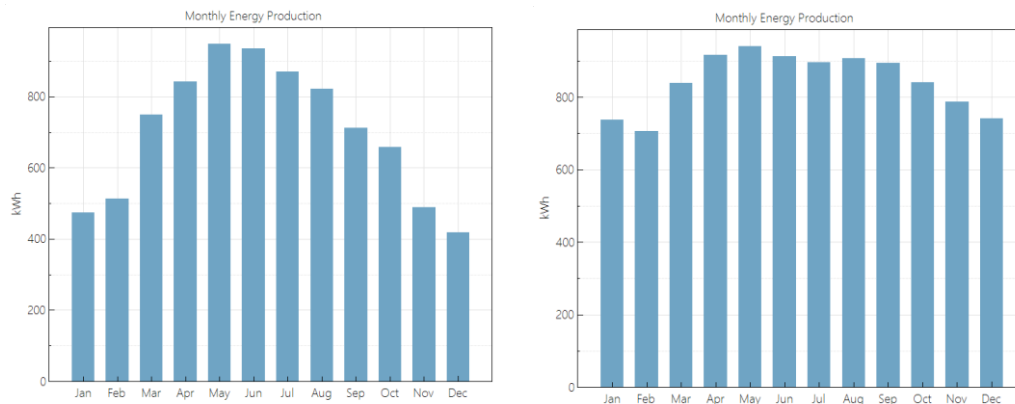


Figure 27: Monthly Energy Production After SRP Rate Change to E-27, West-Facing Panels (Left)

Figure 28: Monthly Energy Production Before SRP Rate Change to E-27, South-Facing Panels (Right)

SRP officials have done a preliminary review of newly installed solar customers installing solar on the E-27 rate throughout 2015. They found that 14% of customers are saving money, while others have essentially changed nothing of their energy use behaviors, ignoring those demand price penalties established during peak demand hours and are thus, paying significantly higher bills. The utility's analysis included the June to January bills of the 190 customers who installed solar since the demand based rate went into effect. Of those customers, the average bill was \$181 prior to solar installations, compared to \$122 each month with solar installed on the E-27 rate. This new pricing turns out to be only a \$29 increase from what those customers would have paid under the previous solar rate, less than the \$50 prediction SRP had stated prior to the rate going into effect.

*Table 7: SRP bills estimates (Source: SRP)*

<b>Average SRP Solar Customer Bills per Month</b>	
<b>Prior to Installing Solar</b>	\$181
<b>Under E-27 (New Solar)</b>	\$122
<b>Under Old Solar Rates</b>	\$93

Those 14% of customers that saved money, likely did so due to a drastic change in energy use behaviors. In fact, their average demand during peak periods was 5.8 kW, a number that rose to 8 kW after 8pm when the peak period ends. This would likely be due to delaying running appliances like washers, driers, etc. until off-peak hours begin.

On the other end of the spectrum, SRP's analysis found that 12% of customers (22 total) were paying \$50 or more each month than they would have under the previous solar rate. These customers' average peak demand use was 8 kW, with off peak demand of 8.9 kW. These customers likely made little no changes in their energy use during peak periods.

This leaves a majority of newly connected SRP solar customers, 74% to be exactly, paying somewhere between \$0 - \$50 more on their energy bills each month compared to what they would have under the previous rate. President/CEO Joy Seitz of American Solar and Roofing suggests that "Consumers have to have a better understanding of how they use their energy (Randazzo, 2016)."

## SOLAR ADOPTION

To quantify the change in solar adoption in the pre-event and post-event periods around the SRP rate change, we looked at the number of applications and installations by month in both the APS and SRP service territories.

The SRP event is visible in a plot of application date versus installation date (Figure 29, top). A large group of customers applied in December 2014 to meet the grandfathering date. No applications are logged from January first until late February, when the rate change was finalized at SRP. The APS trend is included (Figure 29, bottom) for comparison, and we note that there is a less clear mark of another event at APS (as described in Section II, a \$0.70 per solar system kW size charge was added at the end of 2013).

Figure 30 shows the installation totals by month; the SRP rate change is followed by a staggered decrease in installations that roughly correlates to the 100 days that customers typically take to install a project. In comparison, the APS installations by month are steady to increasing in the same period. Applications by month are shown in Figure 31. The impact of the SRP event on solar application is complicated by the anticipation of the event. There is an obvious uptick in applications in December 2014 that doesn't represent the status-quo prior to that time. On December 8<sup>th</sup>, exactly the grandfathering date for the old rate plan, over 500 applications were received (Figure 32). Note that the decrease in applications at the end of 2015 is only an indication that those projects were not yet installed to be included in the 2015 data set.

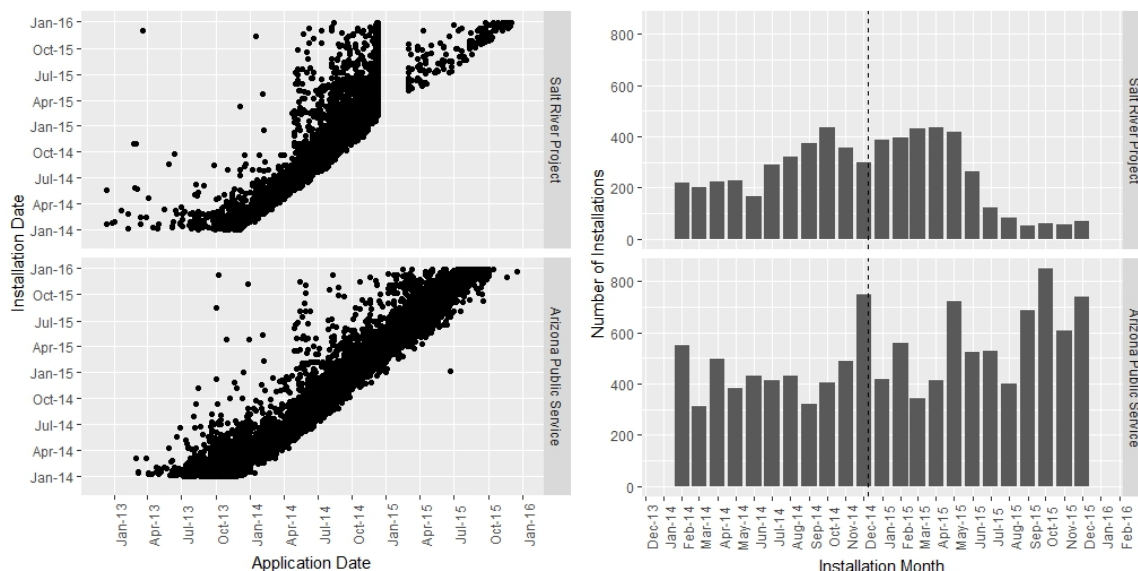


Figure 29: (Left) Application date versus installation date.

Figure 30: (Right) Number of installations per month and the SRP event date of December 8, 2014 marked with dashed line.

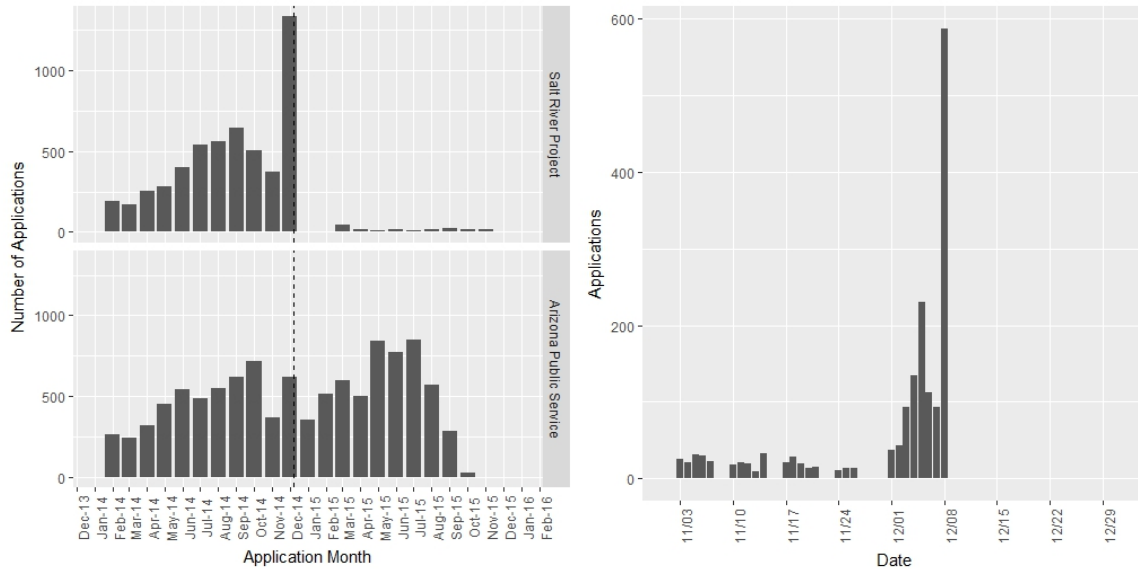


Figure 31: (Left) Number of applications per month and the SRP event date of December 8, 2014 marked with a dashed line.

Figure 32: (Right) Number of applications per day, November and December 2014, SRP.

To understand the impact of the utility rate change on solar adoption, we categorize projects by their application date, and recognize the unusual period around December 8, 2014. We estimated the event's impact in three ways.

The event's impact is highest if considered strictly on the basis of rate eligibility. Figure 33 shows monthly installations grouped by rate eligibility. The monthly installation rate for projects eligible under the old rate from Jan. 2014 to April 2015 is 311 (95% confidence interval [264-357]). Note that projects applying in December 2014 were largely installed by that April 2015. For projects eligible under the new rate, the monthly installation rate from May 2015 through the end of 2015 was 21 [17-25]. A t-test on the monthly installation rates under the old and new electricity rates showed that the rates were significantly different with  $p=2e-9$ . However, this dramatic **decrease of 94%** includes the unusually high period of December 2014.

A second way to interpret the event is to use the application period prior to December 2014 as the baseline, consider the new demand for solar to be the period after January 1<sup>st</sup>, and ignore the applications accepted during the month of December 2014 (Figure 34). For projects which applied prior to the December 2014 rush, the monthly average installation was 287 [244-330] through February 2015 (includes the 100 days period in which projects are typically installed after application). For projects which applied after January 1<sup>st</sup>, the monthly average installations from May to December was 21 [17-25]. (There were no installations on the new rate prior to May 1.) A t-test on the average monthly installation rates for the pre-event compared to post-event groups confirmed that the means are significantly different with  $p=1e-8$ . Clearly the timing of the events is complex and how the applications are accounted for during the critical transition period will impact how the affects are tallied. But this estimation method also says that **monthly installation rate went down by 93%**.



A third way of estimating the impact is to consider the applications accepted during the month of December as represent future demand; customers that likely would have waited longer but because of the upcoming rate change decided to apply at that time (Figure 35). The baseline period is still 287 applications per month. Project applications from December 2014 through December 2015 show an average installation rate of 142 [68-215] per month. A t-test on the pre-event and rush/post-event monthly installation rates showed that the rates were significantly different with  $p=0.004$ . The rate of installations post-event decreased **about only 51%** by this estimate.

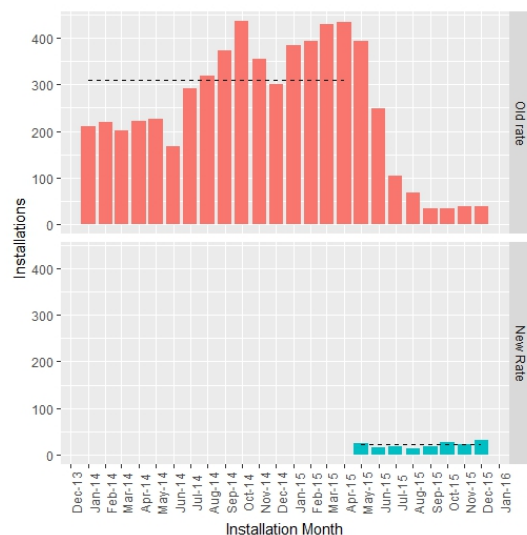


Figure 33 The number of SRP solar projects are grouped by the rate eligibility. Also shown are the average monthly installations under the old and new rates dashed lines (311 and 21).

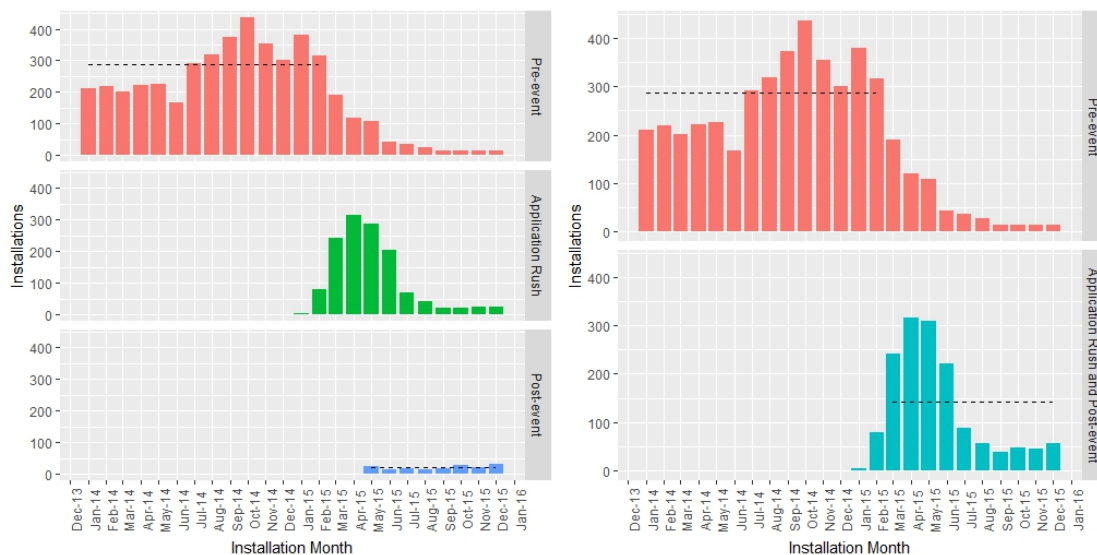


Figure 34: (Left) Number of SRP projects grouped by application date. Pre-event and post-event averages in dashed lines. The categories are Pre-event (applied before Dec. 1, 2014), Application Rush (Dec. 2014), and post-event (applied after Dec 1, 2014).

Figure 35: (Right) Number of SRP solar projects grouped by application date. Averages in dashed lines. The categories are pre-event (applied before Dec. 1, 2014) and Application Rush combined with post-event (applied after Dec 1, 2014).



We also projected the impact on installed capacity through 2016 by using the range of missed installations per month due to the rate change event. According to the monthly installation effects described in this section, each month 145-290 projects were not installed because of the rate change. If the typical project size is 8.25 kW (the pre-event average), each month 1.2-2.4 MW of capacity is not installed due to the rate change. Returning to the EIA 826 net metering data, we can apply this to the total installed residential PV capacity reported for SRP and compare to the other two major utilities: Tucson Electric Power (TEP) and Arizona Public Service (Figure 36). According to the EIA 826 data, SRP ended 2016 with 107 MW of installed residential PV capacity; without the rate change another 29 to 58 MW might exist. An econometrics study that incorporates the growth in APS and TEP markets could further isolate the event and its impacts.

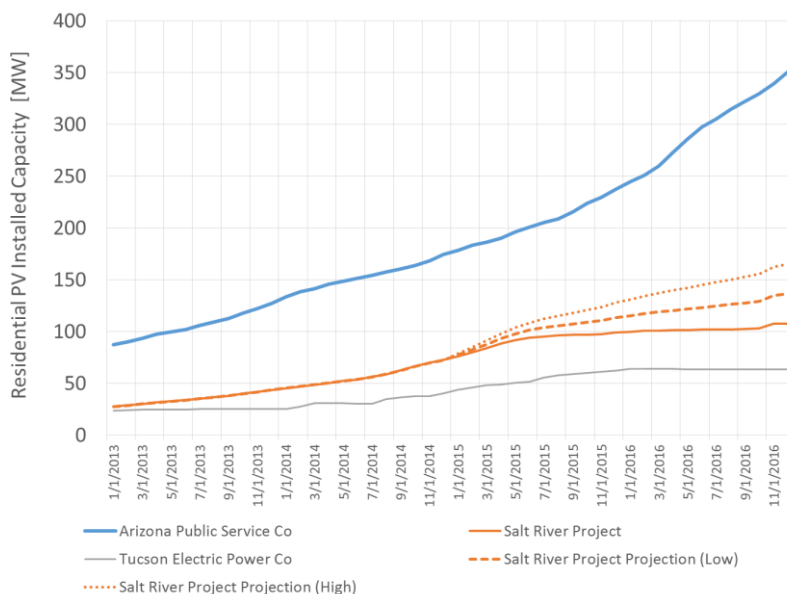


Figure 36: EIA Form 826 Net Metered Data residential solar PV installations by month for three major Arizona Utilities and projections of SRP solar estimated without rate change.

## SYSTEM PRICE

### DATA SET INFORMATION

The following charts convey information about the average monthly price per kilowatt, reported annual PV generation, and system size of arrays in Maricopa County for the Arizona Public Service and the Salt River Project. Data points reflecting appraised values for price were removed, along with abnormal prices that reflected either data entry errors or outlier scenarios. The research team looked at 2014 and 2015 data to study the effects of the December 2014 rate re-structuring at SRP, and also noted the post-event effects of a 2013 change to solar demand charges for APS customers. The market for residential PV systems changed dramatically in both utility service territories over the course of the 2013 application period. Monthly averages of each variable were derived with respect to installation date from January 2014 through December 2015. A system's installation date reflects when the array was physically erected on a buyer's structure, which normally falls around 100 days after the application date.

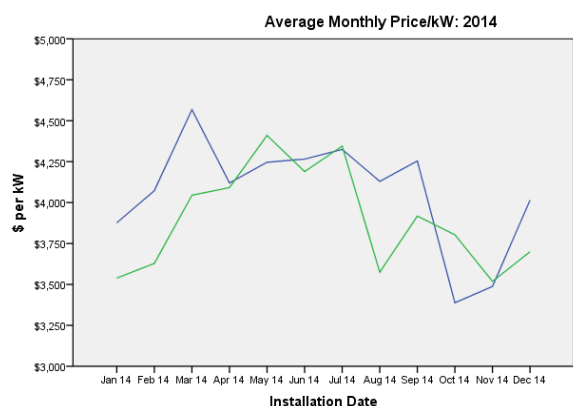


Figure 37: Price per kW, 2014 (Left)

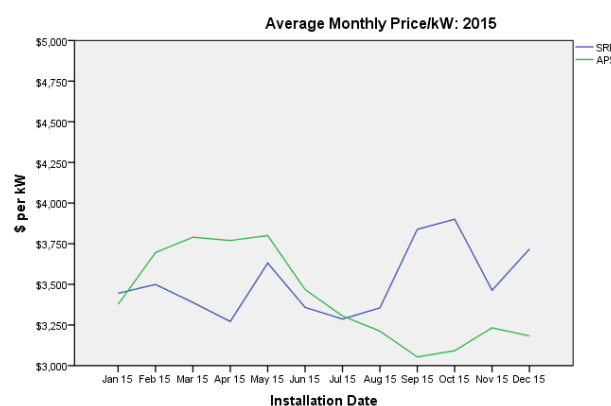


Figure 38: Price per kW, 2015 (Right)

Figure 37 depicts the average monthly price per unit of installed capacity for all systems installed in 2014 for both utilities. Prices for APS trended upward during the first five months of the year climbing from just above \$3,500 in January to nearly \$4,500 by May. Installations during this period likely had application dates that occurred from October 2013 through February 2014. This is notable because it coincides with a late-2013 ruling by the Arizona Corporation Commission (ACC) in agreement with APS' claim that solar customers were not paying their fair share of costs to support maintenance and upkeep of grid infrastructure. The ACC ruled that APS may implement modest demand charges of 70 cents per kW of installed capacity for solar customers in order to recoup some of these costs. At the time of the ruling, average system size for APS solar customers was 7 kW, so the new charges equated to roughly \$5 more on monthly bills for solar customers. It is possible that this jump in price is related to this event, though this finding is inconclusive. During the latter half of 2014 and throughout 2015, prices for solar systems in APS territory appear to be trending down over time as shown in Figure 38.

SRP prices in 2014 appear to move chaotically between roughly \$3,350 per kW and \$4,750 per kW of installed capacity with no discernible pattern. The jump in price from a yearly low in

October of about \$3,350 per kW to about \$4,000 per kW in December could be explained by the announcement of the December 8<sup>th</sup> E-27 rate implementation. However, this hypothesis is tempered by the fact that average monthly prices appear to return to pre-event levels beginning immediately in January 2015. The prices depicted in Figure 38 for SRP show no discernible trend or pattern. Data for 2016 would be helpful in determining if a distinct pattern emerges.

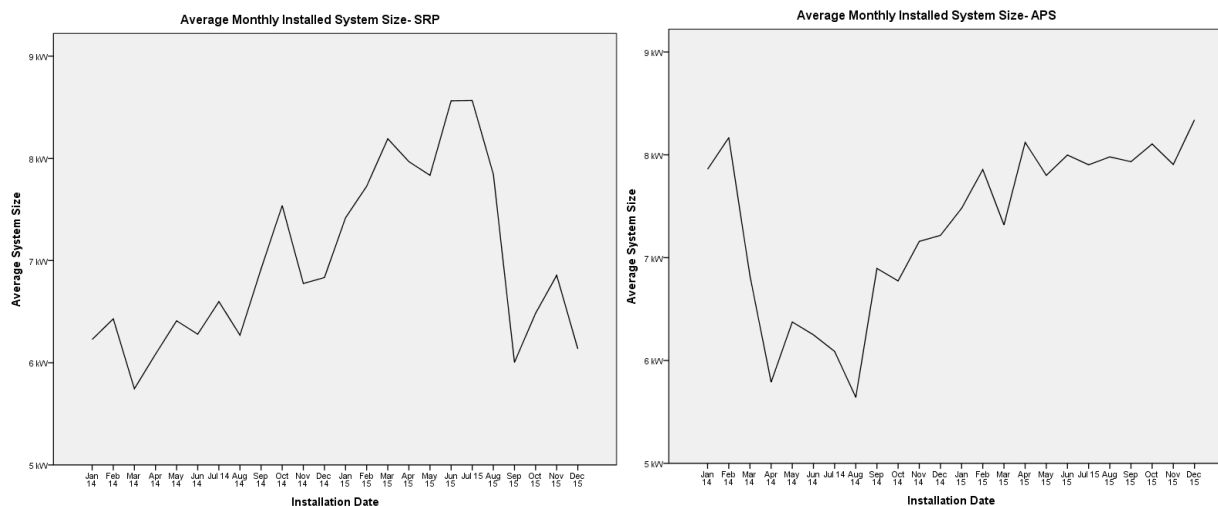


Figure 39: Average installed system size by month: SRP (Left)

Figure 40: Average installed system size by month: APS (Right)

Figures 39 and 40 show the average system size installed for each month of 2014 and 2015 for both SRP and APS. Figure 39 depicts a steady increase in system size beginning in March 2014 and peaking in June and July 2015 before dropping back to early-2014 levels by September 2015. While inconclusive, this movement could partly be attributed to the implementation of the E-27 rate structure in December 2014. PV users often lock in installation prices around the time of application, so effects of rate changes would be expected to appear roughly 90 days following the implementation of a new rate change. Because of the grandfathering clause, one would expect a dramatic uptick in system sizes for applications in November and early December 2014 in order to take advantage of the old rate plan, which would coincide with February 2015 installation dates. While Figure 39 depicts this, what is not clear is why system sizes continue to increase over the next five months, peaking in July 2015 before falling dramatically by September 2015. Ongoing political and regulatory debate over solar pricing policies may explain some of these effects, but more research is needed.

APS appears to show the opposite pattern according to Figure 40, with sharp decreases in system size beginning in March 2014 and remaining low through August 2014, before steadily rising from that point through 2015. March and April 2014 installations coincide with December 2013 and January 2014 application dates, which perfectly coincides with the ACC's approval of APS' 70 cents per solar kW monthly charge in November 2013. Following the initial decrease in system size, possibly caused by the announced demand charge, consumers began gradually increasing their average installed system sizes likely due to an improved economy of scale in which installed price per unit of capacity decreased. These effects are illustrated in Figures 41 and 42.

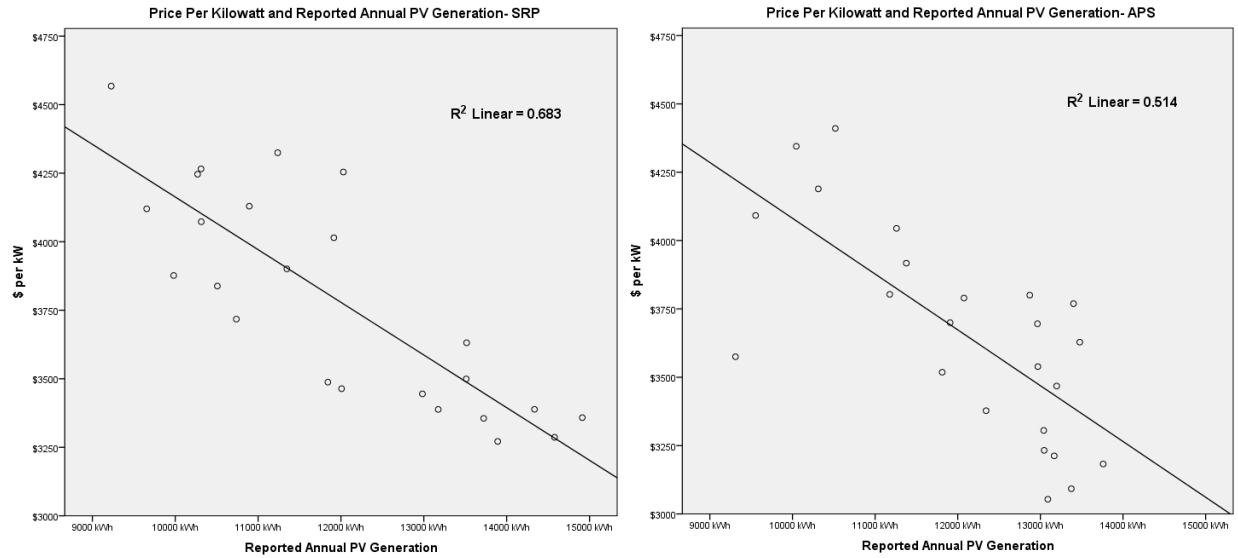


Figure 41: \$/kW v. Reported Annual Power Generation—SRP (Left)

Figure 42: \$/kW v. Reported Annual Power Generation—APS (Right)

Figures 41 and 42 are scatter plots showing the price per kW of systems for SRP and APS in 2014 and 2015, along with their corresponding reported annual electricity generated in kWh. Given reported annual electricity for systems installed in all 24 months, we can reliably predict these systems' price per kW. For both utilities, increases in electricity generation seem to predict decreasing prices per kW of capacity. The correlation coefficient for SRP is 0.683, which is quite strong, and the correlation coefficient for APS is 0.514—also strong. This could be explained by increased competition in the installer market depressing prices, coupled with an economy of scale in which costs of labor and other inputs hold steady for systems no matter the size so that total installed price is roughly equal regardless of the size of the project.

## VI. CONCLUSIONS

Our analysis of solar installations in the Salt River Project territory around the time of the rate change at the end of 2014 shows a decrease in distributed PV adoption coincident with the rate change. Anticipation of the rate change resulted in a sudden increase in applications in December 2014, and those projects were installed through 2015. Because of this unusual installation pattern, it is difficult to estimate the decrease in PV adoption exactly, but monthly installation rates decreased 50 to 95%. As the market stabilizes after the rate change, we expect that more recent data could help better understand the long-term adoption trends (we used installations through 2015 only). Price trends related to the rate change were not clear.

In addition to decreasing adoption, we expect changes in the system characteristics and the marketplace. Interviews suggest that new PV installations under the new electricity rate tend to be west-facing and will likely begin to include more battery storage systems. These changes will allow customers to maximize utility bill savings under the new peak demand rates. Interviews also suggested a decrease in system size and this was confirmed with the dataset as systems under the new rate were on average smaller than under the old rate. Interviews and media reports highlighted the loss of installers that provide third-party ownership type projects in the SRP territory. The dataset also confirmed this change.

Throughout our research, we uncovered additional areas of potential future studies. For example, Arizona Public Service, also in metro Phoenix, is used for comparison. Examination of the same 2014-2015 period showed that this period is marked by the APS rate change at the end of 2013, and itself would make for an interesting event study. Nevada and Hawaii underwent significant state level policy changes which was illustrated in the EIA data and could be studied further. For the SRP event, further econometric study on TTS variables could provide greater detail on price, installer, or additional market impacts. An econometrics approach to the solar adoption data could control for PV market influences such as module price and solar adoption in nearby markets of Arizona Public Service and Tucson Electric Power.

As utilities continue to adapt to the distributed PV market, understanding rate events and their impact on PV markets is important. Experience in this work showed that the exact timing of rate changes as well as anticipation of those changes is key to quantifying the effect of such events.

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